Investigation of the Causes of Leaks in Natural Gas Pipeline Compression Couplings

Report prepared for:

Washington Gas Company
6801 Industrial Road
Springfield, VA 22151

Report prepared by:

ENVIRON International Corporation
274 Main Street
Groton, MA 01450

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ENVIRON

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Executive Summary

In the last two heating seasons, Washington Gas (WG) experienced an unusually high number of leaks in particular areas of their distribution network. The couplings affected include 2 inch and ¾ inch Dresser Style 90 couplings with styrene butadiene rubber (SBR) elastomer seals and 2 inch and ¾ inch Normac couplings with nitrile rubber (NBR) elastomer seals. These couplings were installed between approximately 1958 and 1974.

In both seasons, the increased incidence of leaks occurred in Prince Georges County, MD. Based on composition measurements and system gas flow models, the affected region of the WG system was known to be supplied primarily with re-vaporized LNG from the Cove Point terminal. Other parts of the WG network, which did not receive significant amounts of LNG, experienced typical seasonal leak rates. WG commenced distribution of the Cove Point LNG in August 2003. The high incidence of leaks was first noted in early December 2003 and returned to approximately normal levels in March 2004. A similar pattern was observed the following heating season, with an increase in leaks being reported from November 2004 to March 2005.

Washington Gas retained the services of ENVIRON International Corp. (Environ), working with Polymer Solutions, Inc (PSI) and Akron Rubber Development Laboratory (ARDL) to conduct an investigation into the most likely causes of the increased leak rates. At the outset of our study, potential contributors to this increased leak rate included the effects of changes in gas composition (due to introduction of re-vaporized LNG), historical installation practices, the age of the installed couplings and ground movement due to earthquakes or other causes.

The team has conducted an investigation of the increased leak rates by:

- Gathering information regarding the coupling design and materials, installation practices, leak patterns, gas compositions, geological information, and other LDC experiences with similar equipment;
- Developing a list of all plausible physical and chemical mechanisms which could contribute to the observed leak patterns in the field;
- Constructing a working hypothesis for the observed coupling leaks;
- Designing and conducting experiments to develop the required data to evaluate the hypothesis; and
- Reviewing the experimental data, as well as all other information collected during the assignment, and making our best assessment of the most likely causes of the increased leak rate.

The experiments conducted included exposure tests, in which various seals were immersed in different gas environments for fixed periods, with detailed dimensional, weight and hardness measurements being made before, during and after exposure. In addition we conducted compression stress relaxation tests, in which the retained sealing force produced by the elastomer seal material was measured in different gas environments as a function of time. A key feature of all of these tests was the evaluation of a set of seals that had been exposed to a reference pipeline gas composition for a fixed period and was then switched to the Cove Point LNG environment for a further period. Other sets of seals remained in the reference pipeline gas environment.

Based on the work we have conducted to date, we believe that a combination of factors contribute to the observed spikes in leaks. Three factors have been identified as contributors:

- ***Aging Seals.*** Seals of various rubber formulations have been in service in the WG network for 30 to 50 years. A small fraction of these seals will have undergone compression stress relation to the point of sealing only marginally.
- ***A Change in Gas Composition.*** The change to a gas that has a lower concentration of pentane and higher molecular-weight (C5+) compounds, caused a slight shrinkage in some seals due to de-sorption of previously adsorbed C5+ compounds (especially those seals with an elastomer formulation with a high solvent swell index, a measure of their propensity to adsorb hydrocarbons and increase in volume).
- ***A Temperature Decrease.*** The onset of winter caused a further slight seal shrinkage as the ground cooled, due to differential thermal expansion effects in the coupling.

In addition, the use of hot coal tar as an encapsulant during installation is regarded as a potential contributing factor, in that it may have overheated some seals causing changes in physical properties of the rubbers.

Our conclusion is supported by data from our experiments and can be explained by invoking known physical and chemical mechanisms. It is also very similar to the conclusion reached by LILCO regarding an increased rate of leaks experienced in 1992-3 on Long Island shortly after taking receipt of gas from the Iroquois pipeline.

The adsorption and desorption of heavy hydrocarbons by elastomer seal materials is a reversible process. In further experiments we hope to demonstrate the potential for restoring sealing force by doping the LNG with small quantities of hexanes and/or pentanes.

Key points to note from our test work include:

- Elastomers are viscoelastic in nature and as the word implies, exhibit both elastic behavior as well as viscous behavior. The elastic property is associated with energy storage under deformation: this provides the sealing force. On the other hand, the viscous effects cause a decrease in the stored energy over time. This is known as stress relaxation: the change in stress with time when the elastomer is held under constant strain. This effect causes a decrease in the contact sealing force over time.

- The process of natural gas liquefaction and re-vaporization results in a lower C5+ content (mostly pentanes and hexanes) in the re-vaporized LNG than that of the pipeline gas. The gases used in our experiments demonstrated this difference: concentrations of C5+ hydrocarbons were 1053 ppm in the Shenandoah pipeline gas versus 105 ppm in the Cove Point gas.
- The elastomer in the seals can adsorb and desorb pentane, hexane, and other higher hydrocarbons, resulting in dimensional changes on the order of a few percent to a few tens of percent (if immersed in liquid hexane). In fact, hexane swell tests are a standard way of characterizing synthetic rubbers. Likewise a change from pipeline to LNG gases can result in desorbing of pentane/hexane and a concomitant shrinking of the elastomer seal, leading to a reduction in sealing force.
- Differences in weight change, volume change and micro-hardness change were observed between seals exposed to the pipeline gas and those exposed to the re-vaporized Cove Point LNG. Those exposed to LNG show a slight increase in hardness, a slight decrease in weight and a slight decrease in volume compared to those exposed to pipeline gas. These differences are consistent with increased adsorption of C5+ compounds by the seals in the pipeline gas environment
- The compression stress relaxation tests demonstrated that the change from the pipeline gas environment to the re-vaporized LNG environment can affect the retained sealing force of both the SBR (Dresser) and NBR (Normac) seals. The impact appears to be greater on the NBR material than on the SBR material. The direction of the observed effect supports the hypothesis that the change to a lower C5+ gas caused seal shrinkage, and that this can be a contributing factor to the increased rate of leakage of compression couplings.
- The elastomer seal has a much greater coefficient of thermal expansion than the steel pipe or coupling. Thus as the ground temperature undergoes its seasonal cycles, the seal will grow and shrink relative to the pipe, increasing and decreasing sealing force. In the mid-Atlantic region, the temperature at depths of 2 – 4 feet can fluctuate by ±15 to ±20°F over the course of a year, depending on depth and soil type. The temperature drop of 30 to 40°F from summer to winter is significant and may contribute just enough additional elastomer shrinkage in marginal seals to produce a leak in winter.

We also observed that there are at least two different formulations of NBR elastomer present in the Normac couplings in Prince Georges County. One shows a much greater volume swell in hexane than the other and would therefore be expected to be more susceptible to effects of changes in gas composition. Also worthy of note is the fact that there is a much higher incidence of leaks in couplings installed in the years when Normac couplings represented a significant fraction of the total number installed.

The LILCO (now Keyspan) experience on Long Island in 1992-1993 also appears very relevant. The independent lab retained by LILCO concluded that the reduction in heavy hydrocarbon concentrations as the transition from Transco to Iroquois gas occurred was indeed the proximate cause of the rash of leaks experienced in Normac service couplings.

1. Introduction & Background

In the last two heating seasons, Washington Gas (WG) experienced an unusually high number of leaks in particular areas of their distribution network. The couplings affected include 2 inch and ¾ inch Dresser Style 90 couplings with styrene butadiene rubber (SBR) elastomer seals and 2 inch and ¾ inch Normac couplings with nitrile butadiene rubber (NBR) elastomer seals. These couplings were installed between approximately 1958 and 1974. For reference, Figure 1 shows a 2" Normac coupling after removal from the ground. Figure 2 shows a cross section of a Dresser coupling, illustrating the location and configuration of the elastomer seal (the Normac couplings are very similar in arrangement). Figure 3 shows a seal from a 2" Normac coupling.

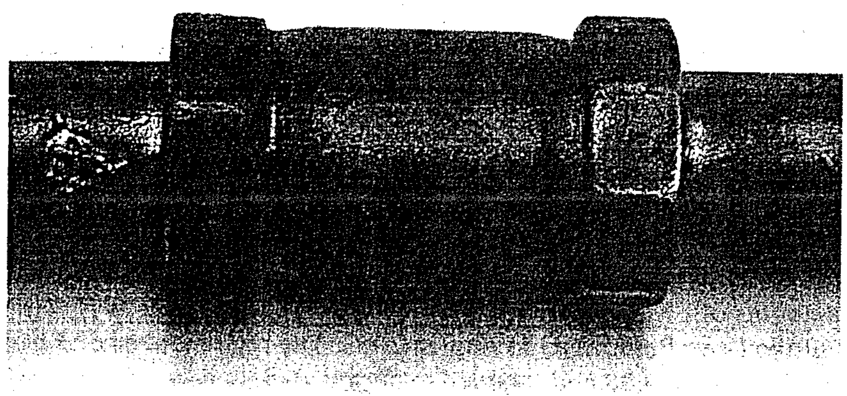


Figure 1 Two-inch Normac coupling, after removal of tar coating.

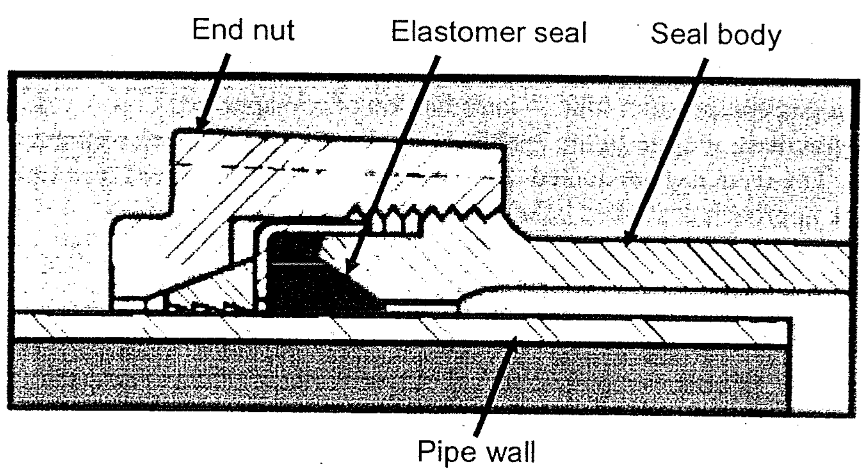


Figure 2 Cross-section of Dresser coupling, showing location of elastomer seal.

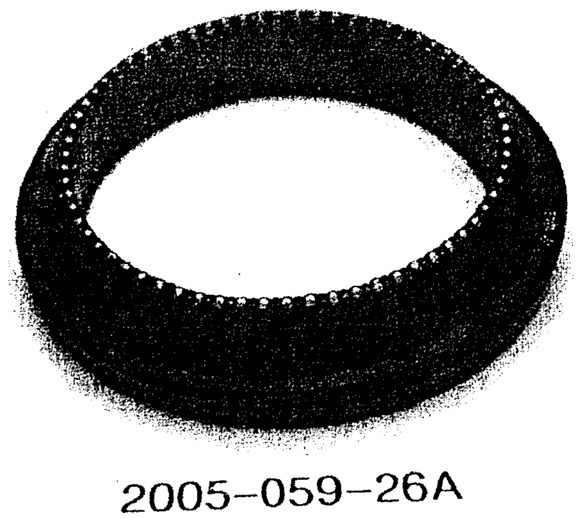


Figure 3 NBR seal from a 2" Normac coupling.

In both seasons, the increased incidence of leaks occurred in Prince Georges County, Maryland. Based on composition measurements and system gas flow models, the affected region of the WG system was known to be supplied primarily with re-vaporized LNG from the Cove Point terminal. Other parts of the WG network, which did not receive significant amounts of LNG, experienced typical seasonal leak rates WG commenced distribution of the Cove Point LNG in August 2003. The high incidence of leaks was first noted in early December 2003 and returned to approximately normal levels in March 2004. A similar pattern was observed the following heating season, with an increase in leaks being reported from November 2004 to March 2005.

Washington Gas retained the services of ENVIRON International Corp. (Environ), working with Polymer Solutions, Inc (PSI) and with Akron Rubber Development Laboratory (ARDL) to conduct an investigation into the most likely causes of the increased leak rates. Potential contributors to this increased leak rate include the effects of changes in gas composition (due to introduction of re-vaporized LNG), historical installation practices, the age of the installed couplings and ground movement due to earthquakes. The team has conducted an investigation of the increased leak rates, following the approach described below:

1. Information Gathering

Working with Washington Gas staff, we began by gathering and compiling information regarding:

- Current and the historical leak problems and patterns in the WG system.

- Current & historical pipeline gas compositions, humidities, pressures and temperatures.
- Geological information.
- Coupling design and materials specifications.
- Coupling installation procedures.
- Coupling purchase history.

2. Identification of Potential Leak Mechanisms & Design of Experiments

We reviewed the data gathered and then proposed a set of candidate explanations for the increase in leak incidents. We considered all plausible physical and chemical mechanisms. We then identified additional data required to support or eliminate a particular scenario from consideration. We designed and performed laboratory and field tests, as well as conducting further research to provide this data.

3. Experimental Investigations

Three sets of experiments were conducted at PSI and at ARDL. ARDL focused on compression stress relaxation measurements in both continuous and non-continuous tests. PSI conducted physical and chemical characterizations of both leaking and non-leaking seals, as well as measuring compression set for various seal samples. In addition, PSI supported in-stream exposure testing conducted by WG staff. These tests are discussed in detail in Section 3.

4. Review of Data and Assessment of Likely Cause

Following the conclusion of the experiments, we reviewed the experimental data, as well as all other information collected during the assignment, and made an assessment of the most likely causes of the increased leak rate. We looked for corroborating evidence from known industry experiences.

2. Possible Causes of Increased Leak Incidents

2.1 Potential Contributing Factors

Following the initial data collection, we identified fifteen potential causes of, or contributing factors to, the increased incidence of leaks in the Normac and Dresser couplings. They are summarized in Table 1 and discussed in turn below.

1. Humidity Change

The process of liquefaction and re-vaporization of natural gas results in a lower water content in the re-vaporized gas than that in pipeline gas. WG data shows that the LNG water content to be an order of magnitude lower than that of pipeline gas (~10 ppm vs 110 – 176 ppm). The elastomer in the seals can adsorb and desorb water, resulting in volume changes on the order of a few percent when immersed in liquid water (this is a much smaller effect than the volume swell caused by immersion in hexane, see below).

Thus a change from pipeline to LNG gases can in principle result in desorbing of water and a concomitant shrinking of the elastomer seal. However, it should be noted that the humidity levels in both gases are extremely low, and consequently this would be expected to be a very small effect and not a likely primary cause. It is considered a possible contributor.

2. Change in Pentane and Higher Molecular Weight Hydrocarbon Content

The process of natural gas liquefaction and re-vaporization results in a lower C5+ content in the re-vaporized LNG than that of the pipeline gas. The hourly composition data provided to us (from Gardiner Road gate) shows approximately an order of magnitude reduction in average C5 plus C6 content as the Cove Point gas was introduced, from ~2000 ppm (C5+C6) to ~200 ppm (C5+C6), see Figure 4.

The elastomer in the seals can adsorb and desorb pentane, hexane, and other higher hydrocarbons, resulting in dimensional changes on the order of a few percent to a few tens of percent (if immersed in liquid hexane). In fact, hexane swell tests are a standard way of characterizing synthetic rubbers.

Thus a change from pipeline to LNG gases can result in desorbing of previously adsorbed pentane/hexane and a concomitant shrinking of the elastomer seal. This factor was suggested as the most likely cause of increased leaks in Normac couplings in the LILCO system during the 1992-3 timeframe. This factor was identified as worthy of experimental investigation.

Table 1 Potential Causes of and Contributing Factors to Increased Leak Incidence

#	Factor	Mechanism	Location-Specific?
1	Humidity change	Elastomer desorbs water & shrinks as gas humidity decreases, reducing sealing force	Yes - local to regions experiencing humidity change
2	C5+ change	Elastomer desorbs C5+ & shrinks as gas composition changes, reducing sealing force	Yes - local to regions experiencing composition change
3	C2, C3, C4 change	Change in elastomer dimensions due to change in interaction	Yes - local to regions experiencing composition change
4	Compression stress relaxation	CSR leads to reduced sealing force over time	Unlikely - all elastomers will experience CSR, but can be a contributing factor
5	Loss of plasticizer	Plasticizer leaches out in HC environment, affecting elastomer properties	Possibly - if leachant is only in certain gas compositions
6	Ground conditions	Ground movement (e.g.due to excessive water) disturbs joint	Yes - local to specific subsurface conditions
7	Earthquake	Ground movement disturbs joint	Unlikely but could be local to specific formations
8	Installation practice	Under/over-tightening, incorrect pipe alignment	Yes - could be specific contractors or crews
9	Hot tar application	Over-temperature due to excessive tar leads to change in elastomer properties	Possibly - could be affected by differing practices between installation crews
10	Pressure increase	Increased pressure overcomes sealing force	Yes - local to regions experiencing pressure increase
11	Sealing surface corrosion	Pitting of sealing surface leading to leaks	Yes - local to regions exposed to corrosive agent or encapsulation failure
12	Low temperatures	Temperature drop reduces sealing force due to differential thermal expansion	Unlikely - all couplings are at same depth in same climate zone
13	Obsolescence	Elastomer life has expired, can no longer provide sealing force	No
14	Off-spec batch of couplings	Off-spec parts causing leak	Unlikely - parts were stocked centrally
15	Coupling design	Design inappropriate for application	No

3. Change in Ethane, Propane and Butane Content

Depending on the source of the LNG, it can also differ in ethane, propane and butane content relative to pipeline gas. In addition, the hourly ethane and propane content can vary significantly as different LNG blends are introduced from the import terminal. The hourly composition data from Gardiner Gate showed ethane content varying between ~3% and ~7% and propane between ~0.4% and ~0.7% as different LNGs were supplied. The periods of high ethane and propane concentration corresponded to increases in nitrogen content, indicating the presence of a higher heating value LNG for which nitrogen blending was required. The background ethane and propane concentrations for the pipeline gas were approximately 3% and 0.6%, respectively. Butane concentrations are typically very low in the LNGs (less than 0.05%) compared to ~0.2% in the pipeline gas.

However, a literature search identified no reports of the effects of changes in C2 – C4 content on elastomer properties, and no plausible mechanism has been identified. In contrast, the effects of heavier hydrocarbons are well documented in the literature and even form part of several standard rubber characterization tests. This effect is therefore not considered a likely cause.

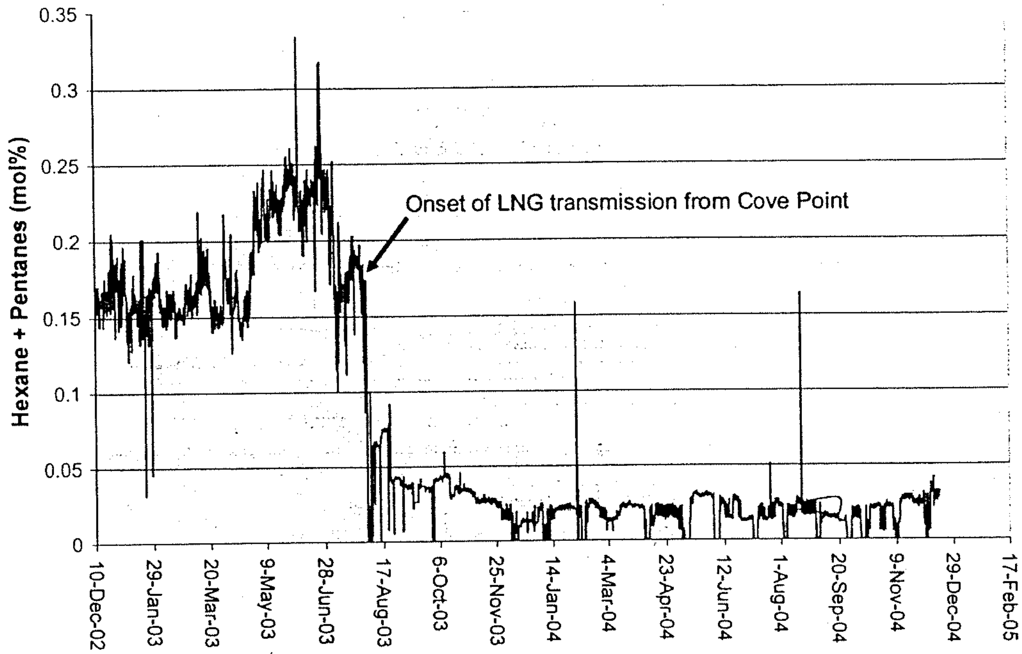


Figure 4 Change in (C5+C6) concentration at Gardiner Gate after start of LNG transmission in August 2003.

4. Compression Stress Relaxation

Elastomers are viscoelastic in nature and as the word implies, exhibit both elastic behavior as well as viscous behavior. The elastic property is associated with energy storage under deformation: this provides the sealing force. On the other hand, the viscous effects cause a decrease in the stored energy over time. This is known as stress relaxation: the change in stress with time when the elastomer is held under constant strain. This effect causes a decrease in the contact sealing force over time. Figure 5 provides illustrative data for an accelerated (high-temperature) test of various elastomers.

All elastomers exhibit this behavior to varying degrees: this is a universally applicable background phenomenon occurring within all the couplings in the WG system. However, it is worth noting that NBR exhibits the lowest retained sealing force among a range of modern elastomers (see Figure 5). It is possible that further physical changes to the stress-relaxed seals (caused for example by desorption of water or C5+) could then cause a marginal seal to leak. This factor was identified as worthy of experimental investigation and a likely contributor.

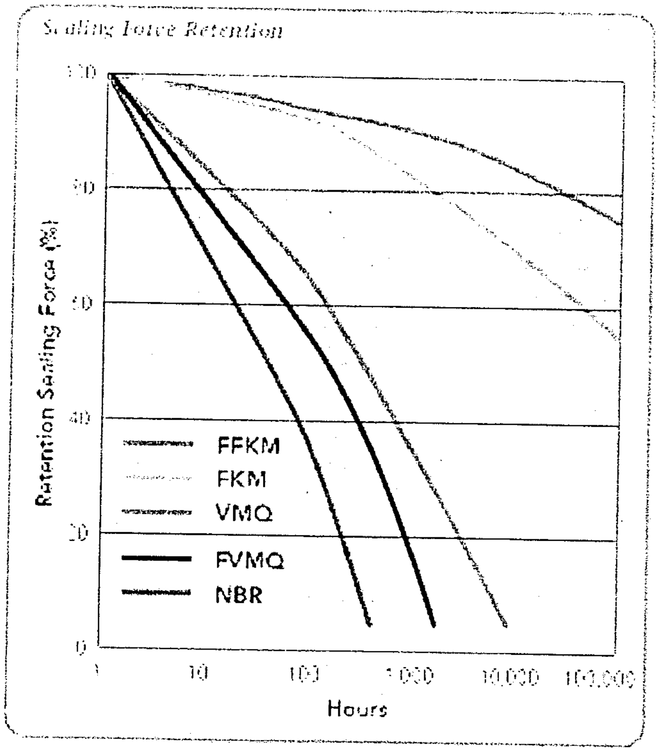


Figure 5 Illustrative compression stress relaxation in various elastomers: Nitrile Rubber (NBR), Fluorosilicone (FVMQ), Silicone (VMQ), Fluoroelastomer (FKM), and Perfluoroelastomer (FFKM). (Accelerated tests conducted at high temperature.) Source: PSP, Inc.

5. Loss of Plasticizer

It was considered possible that constituents of the gas stream may cause plasticizer to leach out of the elastomer, Plasticizers tend to be added to rubber compounds as process aids to enhance softness, flexibility, and processability. A rubber that was soaked in a liquid plasticizer would swell just as it would in a liquid solvent. Therefore, if plasticizer were to leach out over time, the material would be expected to shrink slightly and become stiffer and harder, potentially leading to a drop in sealing force. This phenomenon could be exacerbated by a change in the gas composition to which the elastomer is exposed. No specific mechanism that is dependent on constituents known to be different between pipeline gas and LNG has been identified, however, and this is considered an unlikely contributor.

6. Ground Conditions

Local soil conditions, combined with, for example, unusually high rainfall, could cause local ground motion, which in turn could cause pipe coupling motion leading to a leak. There is some evidence of ground motion in clay soils in Prince Georges County, as well as other counties in Maryland and Virginia. So-called marine clays are widely dispersed in the area (for example, Fairfax County, VA publishes a guide to foundation problems caused by clay swelling and shrinking for homeowners) and there does not appear to be a correlation with or evidence of particular problems in PG County. This is considered an unlikely contributor.

7. Earthquake

An earthquake can also cause local ground motion leading to coupling leaks. Once again, it would be important to examine local sub-surface conditions to determine regions likely to experience greater or lesser degrees of ground motion and to correlate those regions with locations of leaking couplings. Given that the epicenter of the most recent sizeable earthquake was close to Richmond, VA, it is exceedingly unlikely that WG's network in Prince Georges County Maryland would have been preferentially affected over those regions of WG service area in Virginia. After examining ground conditions and reviewing available earthquake data, this potential cause was dismissed (see Section 5).

8. Installation Practice

It is considered possible that there were differences in installation practices by year and area. The challenge in investigating this potential cause of the problem is the lack of availability of detailed installation records which would allow correlation of leak incidents with installation practices. Also, given that the couplings in the WG system have performed well for decades, it is unlikely that installation practices could be the proximate cause of a leak. If installation differences are a contributing factor, then it will only be due to their influence in establishing a range of states of seal in the coupling population before the commencement of LNG transmission. That is, certain couplings, in service for decades, were marginal in sealing performance and could be made to leak by another change in the system (for example, change of gas composition, temperature changes, etc). This is considered a possible contributing factor.

9. Effect of Hot Tar Application

The WG specifications for installing wrapped steel mains call for encapsulation of the coupling with hot coal tar (or "enamel"). The recommended tar temperature for pouring is 400 °F. It is therefore possible that excessive amounts of hot tar surrounding the coupling could provide a large enough thermal pulse to raise the seal temperature excessively. This is obviously closely related to No. 8 above, Installation Practice. Excessive seal temperatures caused by hot tar application could lead to post curing of the material, resulting in a higher extent of cure and thus cure shrinkage. This would result in reduced sealing force. The effect of hot tar application on coupling torque was noted in a WG memo from 1967. Couplings were tightened to a set torque and the retained torque (i.e. the torque required to loosen the coupling) was noted after different time periods. It was observed that the torque loss (i.e. the difference between the original tightening torque and the torque required to loosen the coupling) after a few hours on a fitting treated with hot tar was equivalent to that lost over many weeks on a fitting not so treated. This is considered a possible contributing factor.

10. Increase in Supply Pressure

Operation at increased pressure can obviously overcome marginal sealing force, leading to leaks. However the most recent pressure increases in the region affected were approximately 20 years ago, with no attendant leak epidemic reported. In recent years the pressures in the affected parts of the system have not been increased, so this factor can be dismissed.

11. Corrosion of Sealing Surfaces

Corrosion can lead to surface pitting and leaking of the couplings, despite no degradation in overall elastomer properties. Corrosion could be caused by inadequate cathodic protection, or inadequate sealing of the coupling with tar or wax. Observations of couplings removed from the field indicate no signs of corrosion. Also, there is no reason to suppose that corrosion would occur preferentially in PG County (absent evidence of differences in installation practices). This factor can be dismissed.

12. Low Temperatures

The elastomer seal has a much greater coefficient of thermal expansion than the steel pipe or coupling. Thus as the ground temperature undergoes its seasonal cycles, the seal will grow and shrink relative to the pipe, increasing and decreasing sealing force. In the mid-Atlantic region, the temperature at depths of 2 – 4 feet can fluctuate by ±15 to ±20°F over the course of a year, depending on depth and soil type. The temperature drop of 30 to 40°F from summer to winter is significant and may contribute just enough additional elastomer shrinkage in marginal seals to produce a leak.

Examining the hourly composition data from Gardiner Gate, the weekly fluctuations in concentrations in the summer appear to very similar to those in the winter. Yet, the summer leak rate is much lower than the winter leak rate. It is therefore possible that the winter drop in ground temperature is the proximate cause of leaks in a subset of marginal seals. Contributors to the marginal state of the seals could include improper installation, over-temperature, a long period of stress relaxation, and desorption of moisture and C5+ compounds. Reduced ground temperatures in winter are considered a likely contributor.

13. Obsolescence

The couplings in question were installed between ~1958 and ~1974. It is not known what their expected service life was at the time of installation, but by any standard this is a long service. However, if general obsolescence of the couplings is at fault, then one would certainly not expect increased leak rates in local areas. General obsolescence is not a likely contributor.

14. Off-Spec Batch of Couplings

There exists the possibility that the couplings that are leaking did not meet specifications in some manner. However, this begs the question of timing – why would they leak these last two winters? – and location – why only PG County? The use of a central store of parts for all expansion projects suggests that if they existed, such off-spec couplings would be widely dispersed across the network. It is conceivable, however, that off-spec couplings form that subset which when exposed to other factors (time, composition changes and thermal cycling) develop leaks. This is a possible contributor.

15. Coupling Design

It is possible that the coupling designs were inappropriate for the application. The fact that these couplings have performed adequately over all these years and that the leaks are localized strongly suggests this is not a likely contributor.

2.2 Working Hypothesis

Based on our review of the information available to us at the beginning of our investigation, we developed a working hypothesis for the most likely causes of the increased leak rates, as follows:

1. One or more of several factors led to a subset of couplings that had sub-optimal sealing performance at the time of installation.
2. All couplings reach an equilibrium degree of elastomer swelling due to adsorption of moisture and C5+ compounds from pipeline gas.
3. All couplings undergo compression stress relaxation over the years of operation, reducing sealing force progressively. There develops, over time, a distribution of states of seal in the coupling population, including a normal rate of leaks.
4. In certain parts of the network, exposure to LNG results in elastomer shrinking, due to desorption of moisture and C5+. This results in a set of seals that are marginal.
5. As the winter season starts, the ground temperature falls, resulting in additional shrinkage of the elastomer, leading to leaks in the marginal seals.
6. As spring comes and the ground temperature increases, the leak reporting rate falls back to the historical norm.

A set of experiments which take into account the factors considered the most likely contributors were then designed to test this hypothesis. These factors relate to effects of gas composition changes, and were tested in three sets of experiments: the WG basket exposure tests, the Polymer Solutions Inc (PSI) pressure vessel exposure tests and the Akron Rubber Development Laboratory (ARDL) stress relaxation tests. These will be discussed below.

3. Experimental Program

The overall approach was to understand the effect of a change of gas environment (from pipeline gas to Cove Point gas) on the physical properties of the seals. We were particularly interested in changes in those properties which contribute to the sealing performance of the elastomer, notably the effects on elastomer hardness, volume swell and compression stress relaxation (a measure of the sealing force). In order to be able to draw conclusions from these exposure tests, it was also necessary to perform baseline physical and chemical characterization of the seals. Care was taken in setting up these experiments to ensure that the test conditions were indeed representative of the field conditions and that samples from the field were well characterized.

3.1 Polymer Solutions, Inc. Tests

3.1.1 Approach

PSI conducted a broad range of chemical and physical characterizations of a variety of field samples before, during and after exposure to a variety of gas compositions. Some of the exposure tests were performed in-house at PSI, some were performed in the WG pipeline system itself and some (the compression stress relaxation tests) were conducted at ARDL. PSI performed the detailed physical and chemical characterization of all samples used in the various exposure tests.

Initial Physical and Chemical Characterization. Leaking and non-leaking Normac and Dresser couplings were removed from the field by WG staff and shipped to PSI for inspection and analysis. PSI staff photo-documented and measured the couplings before and after disassembly to remove the seals. They also conducted detailed chemical analyses of the seals to determine (a) if the specimens used in the testing were NBR or SBR, and (b) if there were any differences in the extractables, glass transition temperature or filler levels between among the various seals. By extractables, we mean materials such as uncured rubber, antioxidants, plasticizers, etc, which are identified and quantified by chemical extraction from the seal, followed by chemical analysis. The glass transition temperature, Tg, is the temperature at which the polymer changes from a hard, glass-like state to a rubber-like state. The term filler refers to minerals such as silica or clay, which are typically used in rubber compounding.

A small piece of several seal samples were removed for Fourier Transform Infra-Red (FTIR) spectroscopy. The purpose of the FTIR analysis was to confirm the elastomer types of the Dresser and Normac seals. The results indicate that the Normac seals are a Nitrile (NBR) based elastomer, as indicated by a strong nitrile peak in the spectrum. The Dresser seals, on the other hand, are comprised of a different elastomer, SBR, as indicated on the back of the seal and evidenced by the FTIR spectra.

Gas Exposure Tests. PSI conducted gas exposure tests to understand the effects that the pipeline gas and the Cove Point LNG have on reference SBR and NBR compounds as well as the NBR and SBR seals from the field. The original properties and aged properties (weight, volume, specific gravity and micro-hardness) of the four samples (NBR and SBR, leaking and non-leaking) were measured. At PSI the aging was accomplished by immersing the samples in pressure vessels charged to ~40 psi with the various gases. At the WG field locations, the aging was accomplished by affixing the samples to a strainer basket which was immersed in the gas pipeline flow.

In addition to the material property data, PSI also collected compression set data for all samples. The samples were compressed by 25 percent: i.e. the compressed height is 0.75 times the original height. Then after a fixed time period (typically one week (168 hours) or two weeks (336 hours)) the compression is released and the rebounded height is measured after 30 minutes. The percent set is a percentage of the initial compression state. Thus, for a 100 percent set, the rebounded height is equal to the compressed height. A material with a zero percent set results from the material rebounding to its original height. Compression set can also be related to the mechanical behavior of seals in operating couplings.

Five types of seals were investigated under three gas conditions at PSI and at the WG field locations. The gas conditions were:

- Pipeline gas (at PSI it was Shenandoah, at WG field location it was Rockville.)
- Cove Point LNG.
- One week in the pipeline gas followed by one week in Cove Point LNG.

Samples of a leaking Normac seal, a leaking Dresser seal, a new NBR o-ring, a new SBR Dresser seal, and a blue gasket were prepared for immersion testing in two Washington Gas field locations as well as in pressure vessels at PSI using the gases supplied by Washington Gas. The immersions were sampled at one and two week intervals in the pipeline gas, one and two week intervals in the Cove Point gas, and a third set was immersed for 1 week in the pipeline gas followed by one week in the Cove Point gas. All tests were performed in triplicate – reported standard deviations are based on the results for the three samples.

The only differences in the two approaches are the location of the samples and the pressure. The WG field locations were at ~300 psi, whereas the vessel tests at PSI were conducted at ~40 psi. To simulate gas exchange in the lab, the pressure vessel was evacuated and refilled approximately three times a day.

3.1.2 Test Results

Gas Exposure Tests

Gas chromatograph/mass spectrometer analyses were made of the tests gases used in the PSI and ARDL exposure tests. The gas compositions are presented in Table 2. Of note are the relative concentrations of C5+ hydrocarbons: 1053 ppm in the Shenandoah pipeline gas versus 105 ppm in the Cove Point gas. Also presented are the gas compositions for the in-stream exposure tests conducted at the Rockville and Gardiner Road gate stations in the WG network. C5+ hydrocarbons were 850 ppm on average at the Rockville location (pipeline gas) and 188 ppm on average at the White Plains location (LNG). C5+ concentrations at Rockville varied between 470 and 1296 ppm during the two week test period.

Table 2 Gas compositions for exposure tests at PSI, ARDL and in-stream at WG (concentrations in volume %, ND = Not Detected)

Constituent	PSI & ARDL Exposure Tests		WG In-Stream Exposure Tests	
	LNG (Cove Point)	Pipeline (Shenandoah)	LNG (White Plains)	Pipeline (Rockville)
Methane	95.600	94.142	96.696	94.910
Ethane	3.540	3.039	2.804	3.220
Propane	0.400	0.662	0.395	0.599
Iso-butane	0.025	0.094	0.043	0.069
Normal-butane	0.019	0.135	0.030	0.094
Iso-pentane	0.006	0.044	0.007	0.026
Normal-pentane	0.004	0.033	0.004	0.019
C6+	ND	0.029	0.007	0.039
Nitrogen	0.405	0.776	0.012	0.603
Carbon Dioxide	ND	1.047	0.002	0.419

Weight Change. Table 3 shows the weight percent uptake or increase for two week immersion tests at both PSI and the WG field locations. An increase in weight would occur if the sample adsorbed material from the gas stream (for example, pentane or higher hydrocarbons). A weight loss would occur from physical abrasion (only possible in the case of the in-stream exposure tests at WG) or the loss of a plasticizer or volatile material from within the compound. Since these materials were previously used, it is also possible that adsorbed material from service that could desorb in the gas stream and cause a weight loss during testing.

All aged field samples exposed to Cove Point gas for two weeks showed a weight loss. Two of the aged field samples exposed to pipeline gas for two weeks showed a weight gain and two showed a slight weight loss (much less than that shown by the Cove Point samples). All four aged field samples exposed to pipeline gas for one week and Cove Point gas for one week showed a weight loss, though less than those exposed to Cove

Point gas for two weeks. There is a clear difference in the behavior of the samples exposed to the Cove Point gas and those exposed to the pipeline gas.

Volume Change. Table 4 show the percent volume change for the two-week immersion tests at both PSI and the WG field locations. All aged field samples exposed to Cove Point gas for two weeks showed a volume decrease. Three of the aged field samples exposed to pipeline gas for two weeks showed a volume increase and one showed a

Table 3. Percent weight uptake after 2 weeks in the corresponding gas streams. Aging conducted at PSI (in the vessels) is shown in light yellow and that at Washington Gas in dark yellow.

	Percent Weight Uptake, Cove Point LNG		Percent Weight Uptake, Pipeline Gas		Percent Weight Uptake, Combined 1+1 Week	
Sample	**Percent**	**Standard Deviation**	**Percent**	**Standard Deviation**	**Percent**	**Standard Deviation**
PSI - Leaking NBR	-1.21	.06	-0.56	.06	-0.75	.07
WG - Leaking NBR	-2.60	.09	0.95	.10	-1.82	.34
PSI - Leaking SBR	-1.06	.13	-0.12	.29	-0.36	.30
WG - Leaking SBR	-2.62	.01	1.37	.11	-1.44	.03

Table 4. Percent volume change within the samples after 2 weeks in the corresponding gas streams. Aging conducted at PSI (in the vessels) is shown in light yellow and that at Washington Gas in dark yellow.

	Percent Volume Change, Cove Point LNG		Percent Volume Change, Pipeline Gas		Percent Volume Change, Combined 1+1 Week	
Sample	**Percent**	**Standard Deviation**	**Percent**	**Standard Deviation**	**Percent**	**Standard Deviation**
PSI - Leaking NBR	-1.53	.28	-0.28	.03	-0.79	.08
WG - Leaking NBR	-1.23	.88	2.39	.17	-0.10	.47
PSI - Leaking SBR	-1.27	.10	0.16	.30	-0.47	.46
WG - Leaking SBR	-2.83	.07	3.02	.17	-1.06	.10

slight volume decrease (much less than that shown by the Cove Point samples). All four aged field samples exposed to pipeline gas for one week and Cove Point gas for one week showed a volume decrease.

Micro-hardness. Micro-hardness measurements (see Table 5) were also made on these seals. The hardness data showed very little differences, as deviations of 0.5-1 pts in hardness index are normal. However, it was observed that two of four aged field samples exposed to Cove Point gas for two weeks showed a slight hardness increase. All four of the aged field samples exposed to pipeline gas for two weeks showed a slight hardness decrease. Two of four aged field samples exposed to pipeline gas for one week and Cove Point gas for one week showed a slight hardness increase. Three of four samples exposed to Cove Point gas for two weeks showed a hardness increase in excess of the standard deviation in the measurement, whereas those exposed to pipeline gas or both gases generally showed small changes comparable to the standard deviation. A decrease in hardness is indicative of adsorption swelling, whereas an increase in hardness is indicative of desorption (drying) and/or increased cross-linking.

Table 5. Micro-hardness changes within the samples after 2 week in the corresponding gas streams. Aging conducted at PSI (in the vessels) is shown in light yellow and that at Washington Gas in dark yellow.

	Delta Shore M, Cove Point LNG		Delta Shore M, Pipeline Gas		Delta Shore M, Combined 1+1 Week	
Sample	Delta Shore M	Standard Deviation	Delta Shore M	Standard Deviation	Delta Shore M	Standard Deviation
PSI - Leaking NBR	-0.5	0.5	-0.3	1.0	-0.5	0.9
WG - Leaking NBR	2.5	0.9	-0.5	0.5	1.3	0.6
PSI - Leaking SBR	-0.7	0.3	-0.2	1.3	-0.5	0.5
WG - Leaking SBR	1.5	0.5	-0.2	1.2	0.5	1.7

Table 6. Compression set of the samples after 2 weeks in the corresponding gas streams at room temperature.

Sample	Air	Cove Point LNG	Pipeline Gas	Combined 1+1 Week
2005-059-22 (New Dresser - SBR)	3.8%	4.2%	3.5%	3.1%
2005-059-03 (NBR O-Ring)	3.9%	4.9%	4.4%	3.9%
2005-059-07 Side B (Leaking Normac - NBR)	12.6%	12.4%	13.2%	9.4%
2005-059-05 C2 Side B (Leaking Dresser - SBR)	5.4%	5.0%	3.1%	4.6%

Compression Set. The machined seals utilized for the compression set test were nominally 0.5 inch long strips and the o-rings strips were approximately 1 " long. The two-week compression set data in Table 6 shows some significant differences. The NBR sealing material has approximately twice the compression set of the SBR sealing material. This means that once the NBR is compressed it remains in a compressed state and does not rebound as much as the SBR sealing material. It is difficult to compare the

NBR O-ring to the leaking NBR seal due to the shape differences. However, the leaking and non-leaking NBR seals used in the Normac couplings show similar compression sets. Based on the one and two-week compression set data none of the seals show a significant effect based on the gas environment. This is not unexpected, as compression set measurements generally can not be used to show the effects of small changes in properties.

Physical and Chemical Testing

Solvent Swell. Swell tests were performed separately in chloroform and in hexane. Samples were immersed at room temperature for periods of 70 hours and 168 hours and then removed for weighing and measuring. The hexane swell data in Table 7 shows some interesting differences between the leaking and non-leaking NBR seals. The non-leaking NBR seals have a significantly lower hexane swell and a different specific gravity than their leaking counterparts. The leaking SBR seals have high hexane swell indices also, comparable to those of the leaking NBR seals.

Each measurement was done in triplicate and the standard deviation for the volume swell measurements were approximately ±1 percent. This suggests that there may have been more than one type of NBR seal being used during this time period. A higher state of cure or a different NBR compound with higher acrylonitrile content would cause a lower swell in hexane. It also suggests that those materials that adsorb higher levels of hexane would also be most susceptible to physical changes from variations of the gas supply composition due to absorption and desorption.

Differential scanning calorimetry. Differential scanning calorimetry (DSC) was conducted on most of the couplings. This technique can detect a variety of thermal transitions of a material (such as melting temperature, crystallization temperature, glass transition temperature) as well as other thermal phenomena. In rubber compounds, such as the coupling seals, DSC will typically only detect glass transitions. The glass transition temperature is related to the type and grade of elastomer used. Above this temperature (typically sub-ambient for rubbers), the material will exhibit rubber-like properties. However, below this temperature it becomes very stiff and glass-like. Plasticizers and low molecular weight additives (oils and other organic compounds) can reduce the glass transition temperature of a compound below that of the pure elastomer. This provides improved low temperature resistance with added flexibility down to lower temperatures.

Table 7. Volume swell comparison of seal types when immersed in hexane for 70 hours.

Sample	Seal Type	Leaking	Percent Weight Change	Percent Volume Change

2005-059-06	Dresser - SBR	Yes	18.1	40.4
2005-059-05C2B	Dresser - SBR	Yes	8.4	22.1
2005-059-01	Normac - NBR	No	0.8	4.7
2005-059-01A	Normac - NBR	No	1.0	4.1
2005-059-29	Normac - NBR	No	0.6	3.7
2005-059-08	Normac - NBR	Yes	12.5	29.5
2005-059-07B	Normac - NBR	Yes	11.3	27.3
2005-059-09A	Normac - NBR	Yes	8.4	22.1
2005-059-11A	Normac - NBR	Yes	13.8	33.1

Table 8. Glass transition temperatures of the seals with dates of installation shown. Only sample 2005-059-12 (a leaking Normac), which was installed on 1/29/1965, was not tested.

Sample	Seal Type	Leaking	Tg 1 (°C)	Tg 2 (°C)	Date Installed
2005-059-05c2b	Dresser - SBR	Yes	-49	-	Unknown
2005-059-06b	Dresser - SBR	Yes	-51	-	Unknown
2005-059-28a	Dresser - SBR	Yes	-51	-	6/25/1965
2005-059-28b	Dresser - SBR	Yes	-52	-	6/25/1965
2005-059-01	Normac - NBR	No	-28	-	Unknown
2005-059-29	Normac - NBR	No	-29	-	8/22/1965
2005-059-07b	Normac - NBR	Yes	-65	-16	1963
2005-059-08	Normac - NBR	Yes	-63	-12	9/21/1963
2005-059-09a	Normac - NBR	Yes	-65	-20	1/29/1964
2005-059-11a	Normac - NBR	Yes	-65	-17	1/29/1964
2005-059-26b	Normac - NBR	Yes	-32	-	9/9/1965
2005-059-27b	Normac - NBR	Yes	-61	-9	5/19/1965

Table 8 summarizes the glass transition temperature data for the rubber seals. All the Dresser SBR seals have a glass transition temperature (Tg) of nominally -50°C. All the non-leaking Normac coupling NBR seals have a Tg of nominally -30°C. However, all the leaking Normac couplings NBR seals exhibited two glass transition temperatures: one transition at -65°C and one at nominally -20°C. This data set indicates that the Normac couplings used by WG contained seals of at least two different NBR formulations.

It appears that the Normac seal types were changed around 1965 from a "two Tg" material to a "one Tg" material. The leaking Normac seals (2005-059-07 through 2005-059-11) show two Tg's and were installed in 1963 or 1964. Other Normac couplings (2005-059-26 and 2005-059-29) exhibited one Tg and were installed in 1965. In addition, sample 2005-059-26 is the only single Tg Normac coupling that was submitted as leaking. It should be noted that the pre-1965 two-Tg NBR material in the leaking couplings was the formulation that showed high volume swells in hexane.

The change in formulation is further confirmed by Thermogravimetric Analysis (TGA) scans for a leaking and non-leaking Normac seal. This instrument consists of a microbalance suspended inside a temperature controlled furnace. The sample is placed on the microbalance and the temperature is progressively increased. The data generated is the percent weight remaining on the balance versus temperature. At lower temperatures, weight loss may arise from evaporation of residual moisture or solvent, but at higher temperatures it results from polymer decomposition. The beginning of this change is noted as the polymer degradation onset temperature.

The leaking seal had a lower polymer degradation onset temperature of 402°C whereas the non-leaking seal was 451°C. Both seals contained the same amount of mineral filler, as shown by the residual weight percent at 850°C. However, the carbon black loading is different (measured by the difference in weight loss at 600°C). The leaking seal has 25.4 weight percent carbon black compared to 29.2 percent for the non-leaking seal.

3.2 Akron Rubber Development Lab Tests

3.2.1 Approach

The compression stress relaxation (CSR) tests at ARDL measured sealing force using an industry-standard protocol (Compression Stress Relaxation, ASTM D6147/ (ISO 3384), Method B). It is possible to directly relate this measurement to the field behavior of the seals – the counterforce measured while subjecting the sample to constant strain is analogous to the sealing force provided by an elastomer seal in a tightened coupling.

In this test program we made use of three pressure vessels, each containing a number of NBR (Normac) and SBR (Dresser) sealing material samples installed in standard CSR jigs

- Vessel #1 contained three NBR samples and three SBR samples
- Vessel #2 contained three NBR samples
- Vessel #3 contained three SBR samples

The instrument used was a Wykeham Farrance Compression Stress Relaxation Apparatus. The specimens tested were approximately cubical samples (8.15 mm x 8.15 mm x 6.55 mm) cut from aged elastomer seals. The samples were from seals that had been identified as leaking in the field.

A compressive strain of 25% was applied and all counterforce measurements were made at room temperature. At room temperature, the specimens were compressed to 25% strain within a 30 second period. Thirty minutes after this compression, with the jig/specimen assembly at room temperature, the initial counterforce measurement was made. In the same manner, subsequent counterforce measurements were made at room temperature after completion of 24, 48, 72, 168, 192, 216, 240, 336-hour time intervals. Testing was performed in triplicate using separate specimens.

At the start of testing all three vessels were filled with the pipeline gas to a pressure of 30 psig at ambient temperature. Sealing force measurements were made according to ARDL's standard protocol for one week (i.e. after exposure for 30 min, 24 hr, 48 hr, 72 hr and 168 hr).

After 168 hours of exposure to the pipeline gas, Vessels #2 and #3 were switched to the Cove Point gas. Vessel #1 continued to use the pipeline gas. We again made force measurements according to the standard protocol for one week (again after an additional 30 min, 24 hr, 48 hr, 72 hr, 96 hr and 168 hr), and then weekly thereafter. In these tests, we were assessing whether the change from the pipeline gas to the Cove Point gas can cause a change in the measured sealing force.

Two separate CSR tests were run: the first test used a total of six NBR and six SBR samples, cut from one NBR and one SBR seal, and was run for 336 hours. The second test replicates the methodology of the first test, but using samples cut from a different NBR seal and a different SBR seal. This test has been run for 504 hours as of this writing, and is continuing. In both tests, half of the samples were switched to the LNG environment after 168 hours.

3.2.2 Test Results

The CSR test results are shown in Figures 6 and 7, below. The data are normalized such that the ratio of the measured counterforce to the initial counterforce is plotted as a function of time.

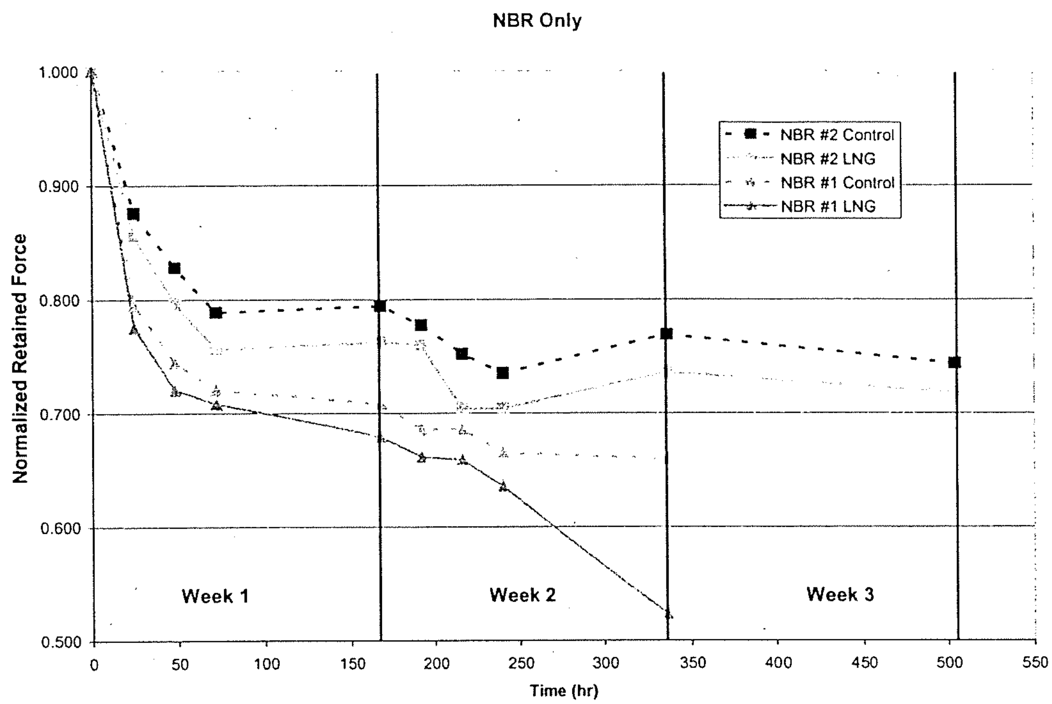


Figure 6 Compression stress relaxation results for NBR seals. Test #1 was terminated after 336 hours. Test #2 is continuing.

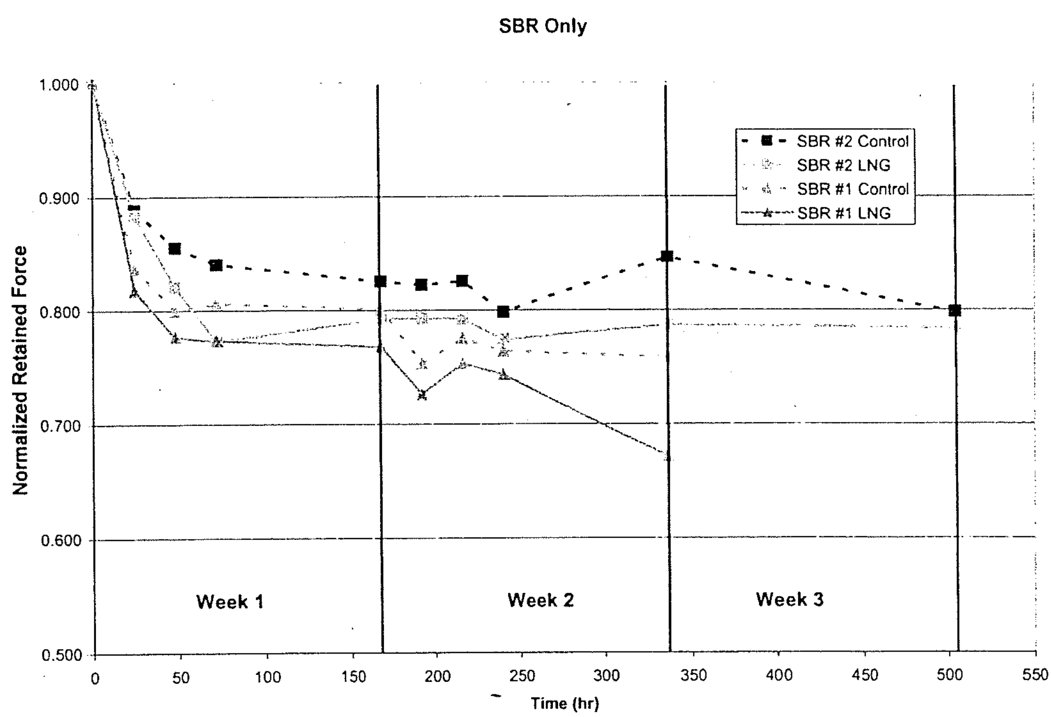


Figure 7 Compression stress relaxation results for SBR seals. Test #1 was terminated after 336 hours. Test #2 is continuing.

Several observations can be made on examination of the ARDL compression stress relaxation data:

- The NBR rubber relaxed considerably more than the SBR, whether exposed to the pipeline gas or the Cove Point LNG. This results in lower retained sealing forces in NBR-equipped Normac couplings than in SBR-equipped Dresser couplings of a similar vintage. This is consistent with the compression set data taken at PSI: the NBR material showed a higher compression set than the SBR material.
- In the first test, both the NBR and the SBR samples exposed to LNG showed a large reduction in sealing force at 336 hours relative to those that remained in the pipeline (or control) gas. The second test also showed a reduction in sealing force in the LNG environment, though less significant than in the first test. This slight reduction was also evident at 504 hours. The NBR material showed a more noticeable effect of the change to LNG than did the SBR material. These effects are consistent with the observed trends in volume, weight and hardness noted in the PSI tests.

4. Other Investigations

4.1 LILCO Experience

In late January, 1992, LILCO begin to receive Canadian natural gas from the Iroquois pipeline through a gate station in western Suffolk county. Prior to this date, the region was supplied with gas from the Transcontinental (Transco) pipeline. Starting in February, 1992, LILCO began experiencing an increased number of leak reports. The leaks were traced to ¾ inch Normac couplings used on gas services installed in the mid to late 1950s. LILCO retained the services of Lucius Pitkin, Inc. (LPI) to assist them in diagnosing the causes of the leaks. The LILCO response to the increased leak rate was investigated by the New York State Public Service Commission, which described the LPI work in its assessment.[1]

According to the NY PSC report, LPI concluded that the leaks in the couplings was due to the desorption of heavier hydrocarbons from the gaskets in the couplings, leading to a shrinkage in the gaskets, leading to a reduced sealing force and a leak path. The driving force for this desorption was the fact that the Iroquois gas contained significantly lower concentrations of heavy hydrocarbons compared to the Transco gas. This conclusion was based on a series of experiments conducted on seals removed from the field. LPI exposed seals to Transco and Iroquois (and other) gas environments and then performed weight measurements, dimensional analysis and load relaxation tests.

The change in C5+ content from Transco to Iroquois gas was from ~1500 to ~300 ppm, with C6+ being reduced from ~500 to ~100 ppm. This change in C5+ concentration is comparable to that experienced by WG in PG County with the change from pipeline gas to Cove Point LNG (see Table 9).

Table 9 Comparison of changes in gas composition in the LILCO and Washington Gas systems (Concentrations in volume percent).

	LILCO		Washington Gas	
	Transco	Iroquois	Shenandoah	Cove Point
Methane	95.400	94.900	94.142	95.601
Ethane	2.380	2.200	3.039	3.540
Propane	0.560	0.230	0.662	0.400
Butanes	0.340	0.050	0.229	0.044
Pentanes	0.100	0.020	0.077	0.011
C6+	0.050	0.010	0.029	0.000
Nitrogen	0.300	1.800	0.776	0.405
Carbon Dioxide	0.850	0.700	1.047	0.000

[1] State of New York, Department of Public Service, Case 93-G-0401, Report dated July 26, 1993.

4.2 Ground Movement

We evaluated the likely contribution of ground movement, caused either by earthquake or by excessive ground water factors. An earthquake of magnitude 4.5, occurred in December 2003, with an epicenter location in Virginia, approximately 155 km southwest of Prince Georges County. It is known that seismic induced ground motion can result in pipeline leaks and/or ruptures resulting from ground deformation under certain geologic and hydrogeologic conditions, given an earthquake of sufficient strength.

Leaks and/or ruptures in buried pipelines due to seismic impacts can result from either ground-strain due to seismic wave propagation or permanent ground deformation and failure (e.g., landslides, liquefaction, differential settling/subsidence) Buried pipeline damage is much more likely to result from permanent ground deformation (e.g., liquefaction), than from wave propagation effects.

Ground motion due to differential settling/subsidence of soils, is typically associated with earthquakes having a magnitude > 6.3. During the past 40 years, no earthquake within 200 km of Prince Georges County has exceeded a magnitude of 5.0; and only five earthquakes have exceeded a magnitude of 4.0. They are listed in Table 10

Table 10 Earthquakes within 200 km of Prince Georges County, MD since 1984.

Year	Month/ Day	State	EQ Magn.	Approx. Distance from Prince Georges County (City of Brandywine)
1984	April 23	PA	4.4	~ 145 km North
1984	Aug. 17	VA	4.2	~150 km Southwest
1994	Jan. 16	PA	4.2	~190 km North/Northeast
1994	Jan. 16	PA	4.6	~190 km North/Northeast
2003	Dec. 9	VA	4.5	~155 km South/Southwest

Ground liquefaction is associated with:

- Favorable near-surface geologic/soil conditions
- A shallow water table (< 30 feet)
- Earthquake intensities (Modified Mercalli Intensity, MMI) ≥ VI[2]

[2] Earthquake strength can be expressed both quantitatively in terms of magnitude (the Richter Scale) and qualitatively in terms of intensity (the Modified Mercalli Scale).

Liquefaction is more likely to occur in unconsolidated water-saturated granular soils. In-situ soil tests are typically used to evaluate the potential for liquefaction. Although site-specific tests were not performed for this investigation, it is known that both Prince Georges County and the eastern portion of Fairfax County are underlain by unconsolidated gravel, sand, silt, and clay sediments, which increase in thickness towards the Chesapeake Bay. Therefore, it is possible that some soils in these areas may be susceptible to liquefaction given an earthquake of sufficient strength.

A shallow water table (within <30 feet of the ground surface) has also been associated with increased risk for liquefaction. Based on USGS well measurements, normal water table depth in Prince Georges County is < 30 feet (USGS Groundwater Database). Above-normal rainfall resulted in water table depths of < 20 feet in Prince Georges County during 1983/1984, 1993/1994, 1997/1998 and 2003.

Ground motion due to liquefaction is typically associated with earthquakes having an Modified Mercalli Intensity (MMI) ≥ VI. The 2003 Virginia earthquake (magnitude 4.5) was felt in the Washington D.C. area. Although reported intensities at the epicenter (approximately 155 kilometers southwest of Prince Georges County) ranged from V to VI, see Figure 8, reported intensities in the Washington D.C. area ranged from II – IV, and are therefore very unlikely to have resulted in liquefaction of soils in this area which includes Prince Georges County. These intensities are defined as follows:

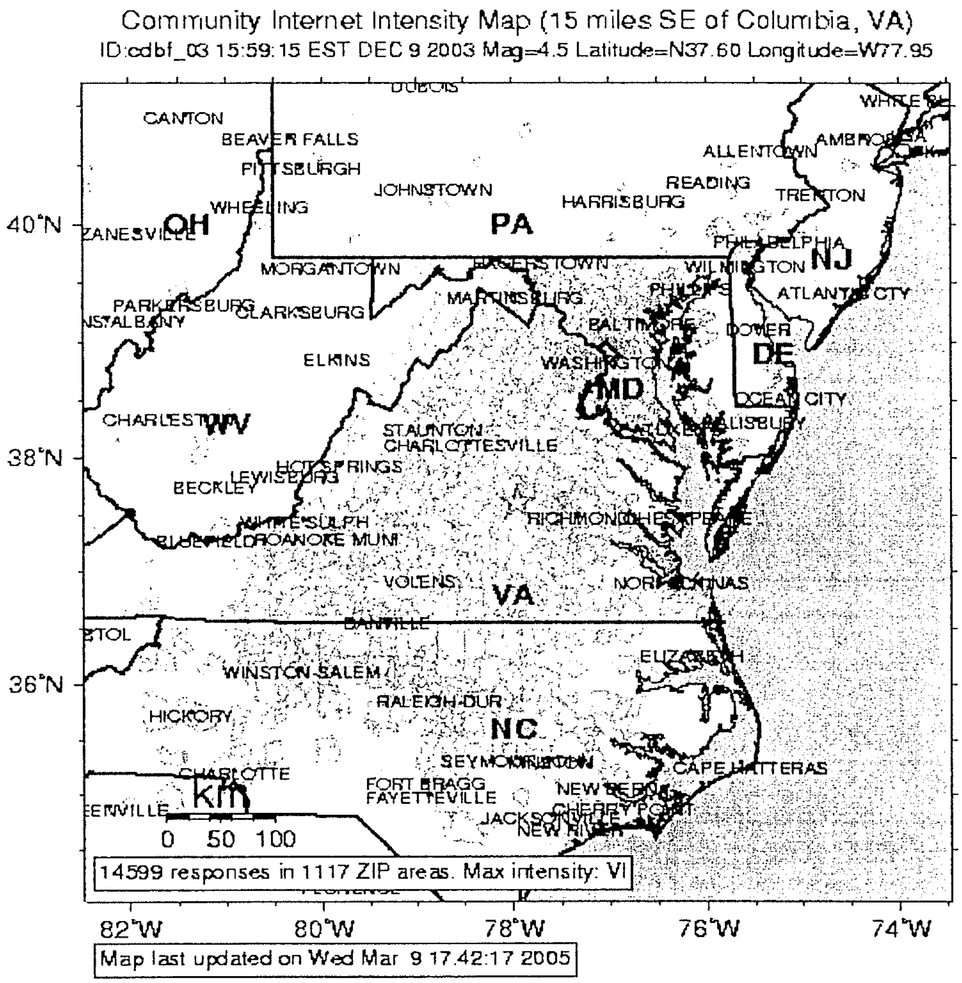
MMI II: Felt only by a few persons at rest, especially on upper floors of buildings. Delicately suspended objects may swing.

MMI III: Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibration like passing truck. Duration estimated.

MMI IV: During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, and doors disturbed; walls make creaking sound. Sensation like heavy truck striking building. Standing motorcars rock noticeably.

In summary, we believe that the 2003 VA earthquake is unlikely to have resulted in sufficient ground motion to damage the utility pipelines in Prince Georges County for the following reasons:

- Ground subsidence is associated with earthquakes of greater magnitude (>6.3), much greater than the 2003 VA earthquake; and



INTENSITY	I	II-III	IV	V	VI	VII	VIII	IX	X+
SHAKING	Not felt	Weak	Light	Moderate	Strong	Very strong	Severe	Violent	Extreme
DAMAGE	none	none	none	Very light	Light	Moderate	Moderate/Heavy	Heavy	Very Heavy

Figure 8 Reported intensities for December 2003 earthquake.

- Although geologic and hydrogeologic conditions in Prince Georges county suggest the potential for liquefaction, the observed intensity of the 2003 VA earthquake in the vicinity of the Prince Georges county (intensity range: II-IV) is very unlikely to have resulted in ground liquefaction.

4.3 Historical Data

A year-by-year analysis of the leaking couplings from the last two winters shows a clear peak in leaks in those installed in the timeframe 1962-1965, see Figure 9.

Miles of Main and Leaks Per Year

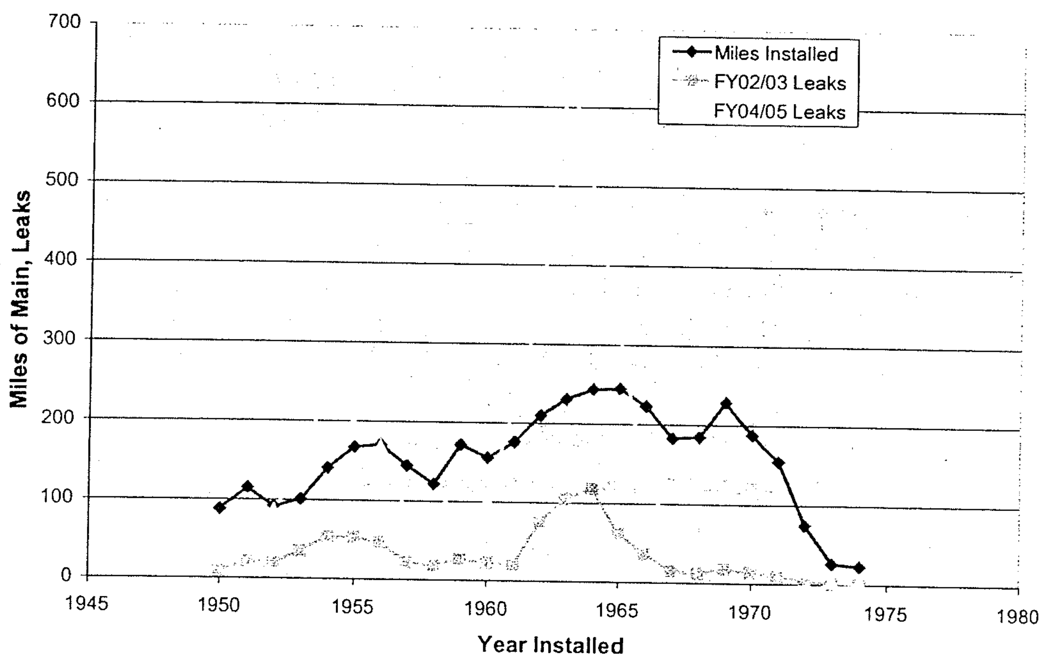


Figure 9 Miles of main installed by year and reported leaks for the last two heating seasons, plotted by year of installation of coupling.

However, this period was one of major expansion, and significant numbers of couplings were installed. The charts below (Figures 10 & 11) show the number of purchases of each manufacturer's couplings by year for the 2 inch and ¾ inch sizes. Figure 12 shows the percentage leak rate by year of installation. This data was developed by adding the leaks for each year of installation over the last two winters and dividing the total by the number of ¾ inch and 2 inch couplings purchased that year. As we do not have installation data by year, we assume that couplings were installed in the year of purchase. The data in Figure 12 still shows that couplings installed in the period 1962-1965 are leaking at a higher rate than those installed later, though the difference in leak rate is not as pronounced when normalized by number of installations in this manner. This points to a difference in either product quality or installation practice in this timeframe.

It is worth noting that the installation years which are showing the highest leak rate (1962-1965) correspond to those years in which Normac purchases were approximately equivalent to Dresser purchases. In other years (with the exception of ¾ inch purchases in 1968-1969), Normac couplings were not purchased. We do not have data on the relative leak rates of Normac and Dresser couplings over the last two winters.

Use of Normac couplings was discontinued by WG in 1966 and no further purchases of 2" Normac couplings were made. However, in 1968-1969, ¾ inch Normac couplings were again used by WG.

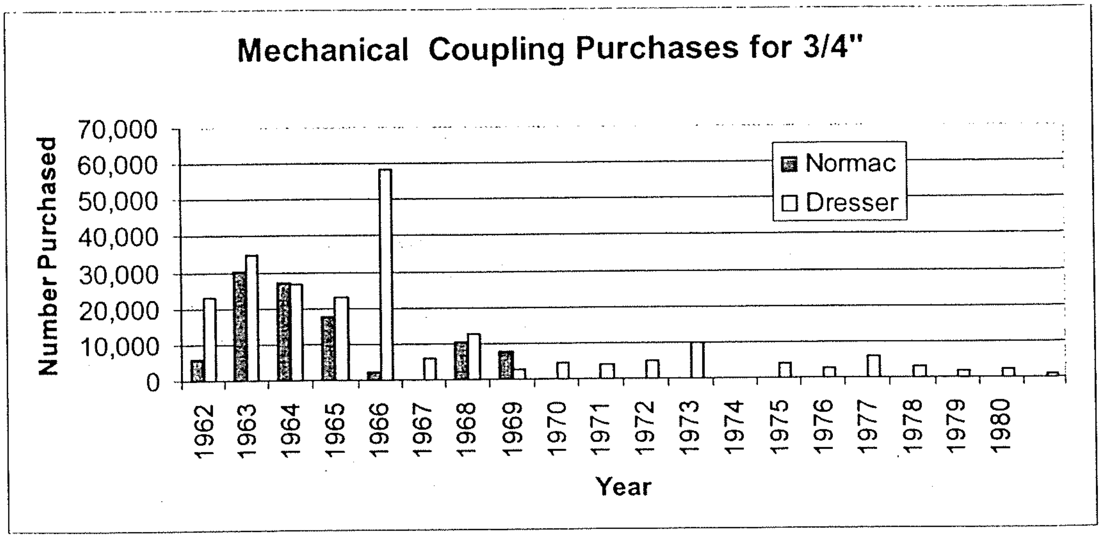


Figure 10 Purchasing history for ¾ inch couplings.

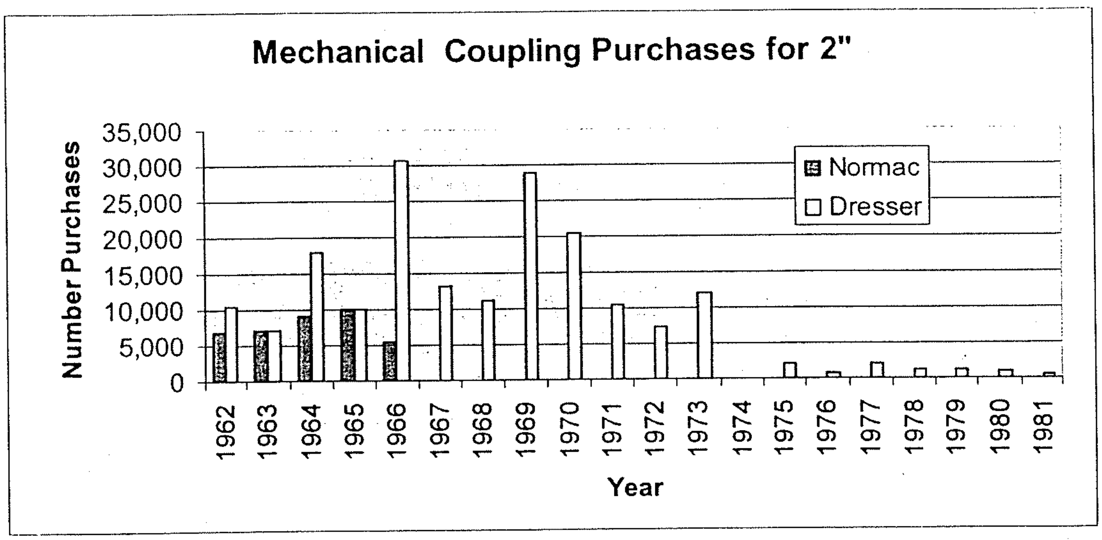


Figure 11 Purchasing history for 2 inch couplings.

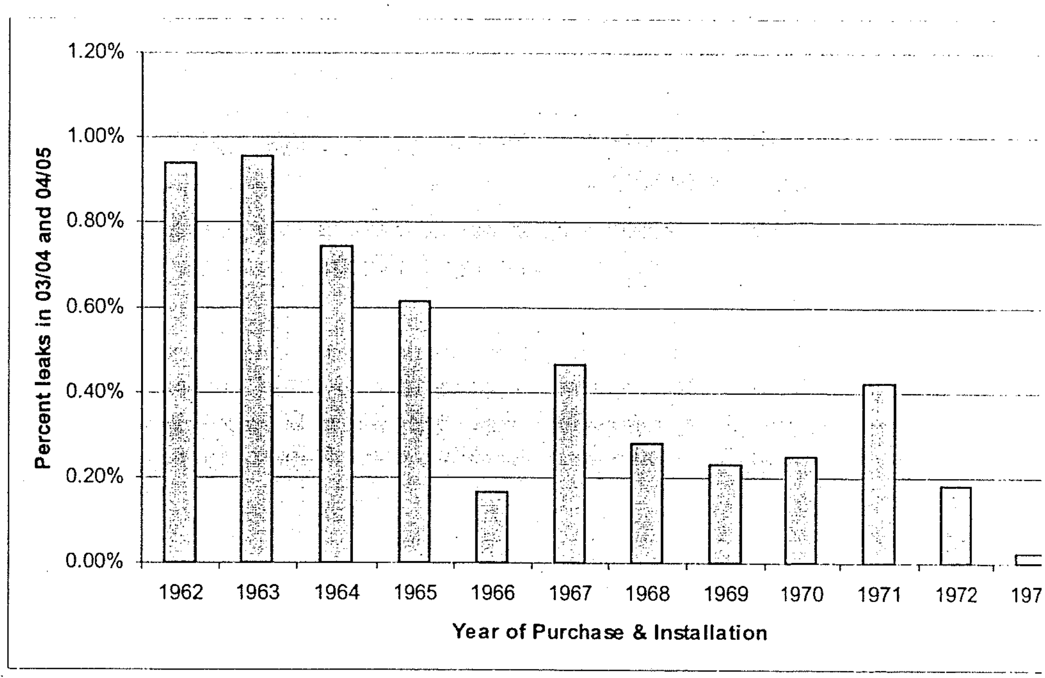


Figure 12 Percentage leak rate (over last two winters) by year of coupling purchase and assumed installation.

5. Conclusions

Several conclusions can be drawn from the experimental program and data review conducted thus far.

- Differences in weight change, volume change and micro-hardness change were observed between seals exposed to pipeline gas and those exposed to re-vaporized Cove Point LNG. Those exposed to LNG show a slight increase in hardness, a slight decrease in weight and a slight decrease in volume compared to those exposed to pipeline gas. These differences are consistent with desorption of C5+ compounds from the seals in the LNG environment.
- The change from the pipeline gas environment to the re-vaporized LNG environment can affect the retained sealing force of both the SBR (Dresser) and NBR (Normac) seals used in the compression couplings installed by WG between the 1950s and the 1970s. The impact appears to be greater on the NBR material than on the SBR material. The direction of the effect observed supports the hypothesis that the change to a lower C5+ gas caused seal shrinkage, and that this can be a contributing factor to the increased rate of leakage of compression couplings.
- There are at least two different formulations of NBR elastomer present in the Normac couplings in PG County. One shows a much greater volume swell in hexane than the other and would therefore be expected to be more susceptible to effects of changes in gas composition.
- There is a higher incidence of leaks in couplings installed in the years when Normac couplings represented a significant fraction of the total number installed.

The LILCO (now Keyspan) experience on Long Island in 1992-1993 appears very relevant. The independent lab retained by LILCO concluded that the reduction in heavy hydrocarbon concentrations as the transition from Transco to Iroquois gas occurred was indeed the proximate cause of the rash of leaks experienced in Normac service couplings.

The evidence supports our principal hypothesis, which is as follows:

1. All couplings undergo compression stress relaxation over the many years of operation, reducing sealing force progressively.
2. All couplings reach an equilibrium degree of elastomer swelling due to adsorption of moisture and C5+ compounds present in the pipeline gas.
3. In certain parts of the network, exposure to LNG results in slight elastomer shrinking, due to desorption of C5+.
4. These three factors result in a set of seals that are marginal.

5. As the winter season starts, the ground temperature falls, resulting in additional shrinkage of the elastomer, leading to leaks in the marginal seals.
6. As spring comes, the ground temperature increases and the leak reporting rate falls back to the historical norm.

Our test results indicate that the change to LNG is a contributing factor, in that a change in gas composition causes shrinkage in the seals leading to a reduction in sealing force. However, the seal population in general contains a subset that is sealing marginally: this is evidenced by the normal rate of seal leaks in all parts of the WG network, including those which have not been exposed to LNG.

There is no fundamental incompatibility between re-vaporized LNG and the compounds used in the NBR and SBR seals used by Normac and Dresser. In fact, we would hypothesize that properly installed seals exposed only to re-vaporized LNG would function well for decades also.

Thus we conclude that a combination of factors contributes to the observed spikes in leaks:

- ***Aging Seals.*** Seals of various rubber formulations have been in service in the WG network for 30 to 50 years. A small fraction of these seals will have undergone compression stress relation to the point of sealing only marginally.
- ***A Change in Gas Composition.*** The change to a gas that has a lower concentration of C5+ compounds, caused a slight shrinkage in some seals due to de-sorption of previously adsorbed C5+ compounds (especially those seals with an elastomer formulation with a high solvent swell index).
- ***A Temperature Decrease.*** The onset of winter caused a further slight seal shrinkage as the ground cooled, due to differential thermal expansion effects in the coupling.

Finally, it should be noted that the adsorption/desorption of heavy hydrocarbons by elastomer seal materials is a reversible process. In further experiments we hope to demonstrate the potential for restoring sealing force by doping the LNG with small quantities of hexanes and/or pentanes.

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News Article

Rita severely damages BHP Billiton's Typhoon platform

28/9/05:

BHP Billiton's multi-million dollar Typhoon oil and gas platform has been ripped from its moorings in the Gulf of Mexico and severely damaged by Hurricane Rita.

The platform, which can produce 40,000 barrels of oil and 60 million cubic feet of gas a day, was found floating in the Gulf on Monday miles from its usual position.

BHP Billiton and Chevron each have a 50 per cent stake in the tension leg platform, which is normally moored in 2,000 feet of water about 165 miles south-west of New Orleans.

It was found on Monday only 60 miles from the coast, south of Atchafalaya Bay.

About three million people fled their homes as category-three Hurricane Rita approached but there was no repeat of the havoc caused by Hurricane Katrina, which killed more than 1,000 people when it struck on August 29.

All BHP Billiton employees were evacuated from the Gulf and the company's Houston office before Rita hit.

BHP Billiton spokeswoman Emma Meade said the Typhoon platform had been severely damaged in the storm.

"We are now just trying to secure the facility, but it is too early to say what will become of it," she said.

BHP Billiton could not say how much the rig was worth, but the infrastructure required to bring it into production alone cost $US256 million ($A336.36 million at Tuesday's exchange rate).

Meade said an investigation would be carried out into why the platform, which took a direct hit from Rita, left its moorings.

"The facility is designed to withstand the effects of severe hurricanes, so we are not sure why it has gone off location," she said.

BHP Billiton has started fly overs of all its other interests in the Gulf and but so far has not found any other damaged platforms.

The company's Houston office is due to reopen on Wednesday.

The news was better for Woodside Petroleum, which has not yet discovered any damage to its gas operations in the Gulf.

"We have assessed some platforms and some rigs and there are no signs of damage so far, but we are continuing our assessment," Woodside spokesman Roger Martin said.

All of the 15 platforms that Woodside has an interest in were shut down as Rita approached, but some are already back in action.

Martin said production was back up to about three million cubic feet (mmcf) of gas per day, compared to normal production of 24 mmcf, and the company hoped to be back to full production by the end of the week.

Oil and gas junior Petsec Energy said its Vermilion 258 platform in the Gulf suffered only minor damage from the hurricane and is expected to recommence production late this week.

http://www.rgj.com/news/stories/html/2005/09/20/108772.php?sps=&sch=&sp1=leader-courier&sp2=Leader-Courier&sp3=Fernley&sp5=theLeader-Courier.com&sp6=news&sp7=news_front&jsmultitag=news.rgj.com/fernley

Static electricity cause of tanker truck fire

Betty Aleck
Leader-Courier
9/20/2005 02:22 pm

FERNLEY — The cause of a tanker truck fire - filled with 10,000 gallons of natural methane gas - last Wednesday on the grounds near the Truck Inn complex appears to have been caused by static electricity.

North Lyon County Fire Protection District Chief Jim Lemke, who served as Incident Commander, reported static electricity most likely was the cause of the fire and there is a possibility that "firefighters started the fire," but he further reported since there is no physical evidence available that theory cannot be verified.

At about 10:15 a.m. on Sept. 14 the Reno Regional HAZMAT Team arrived at the scene to assess the incident.

"The hazmat team was monitoring where the gas was going and it's likely the static electricity from them (firefighters) ignited the gas," said the NLCFPD Chief.

At that time the HazMat team was poised to shut off a leaking valve when the liquid gas ignited. Lemke said the HazMat team was not close enough to the tanker truck to be affected by the ignition.

Once the fire erupted, flames stretched 40 feet into the air and then fire officials decided to evacuate the area.

"Our fire crews played a small part of a large contingent of resources," said Lemke (also see other story on A10), but he noted NLCFPD firefighters were first on scene and did a good assessment of the incident.

Lemke, who arrived second on the scene, immediately called for fire resources out of Reno and Sparks.

Once the decision was made to evacuate businesses within the Truck Inn complex, NLCFPD firefighters began knocking on doors asking patrons and business employees to vacate the area, with other resources used to contact residents.

"Everything we did is what we should have done," said the District Chief, who added that although business owners, employees, patrons and residents were inconvenienced by the evacuation, the fire district took "legitimate action in the best interest of the public."

The flames from the Clean Energy tanker burned throughout Wednesday night, then it burned all day on Thursday and finally burned out at 2 a.m. Friday morning.

Lemke reported the Clean Energy truck driver, from the Dallas, TX, based company, tried to fix the valve stem located at the rear of the tanker, which is called the doghouse. The trucker, though, was unsuccessful and the assembly fell apart, which caused the leak.

Eyewitnesses at the Truck Inn and surrounding businesses reported seeing a grayish vapor rolling out from the rear of the truck at about 7:30 a.m.

Lemke noted Clean Energy, would be billed by the various fire agencies that responded to the fire for costs associated for the response

At about 2 p.m. a Reno Fire Department technical specialist for the HazMat Unit determined the immediate danger had passed and that the inner tank would not breach, which would have caused an explosion.

"Everything went well and we didn't have a large explosion or incident," said Lemke. He added at the District's Main Street Fire Station, 14 engines and three tenders were waiting with assignments if there was an explosion.

Further, an assembly of firefighters from various agencies waited at the Command Center at the Fernley-Wadsworth Lions Club's motocross racetrack on Vine Street, ready for response.

Responding to the incident were crews and apparatus from NLCPFD, Churchill County, Central Lyon County Fire Protection District, Storey County, Reno Fire Department, Sparks Fire Department, Truckee Meadows Fire and Naval Air Station Fallon.

Lemke and fire officials from Reno and Sparks will meet this week to critique the incident.

(See related story on evacuation, I-80 closure)